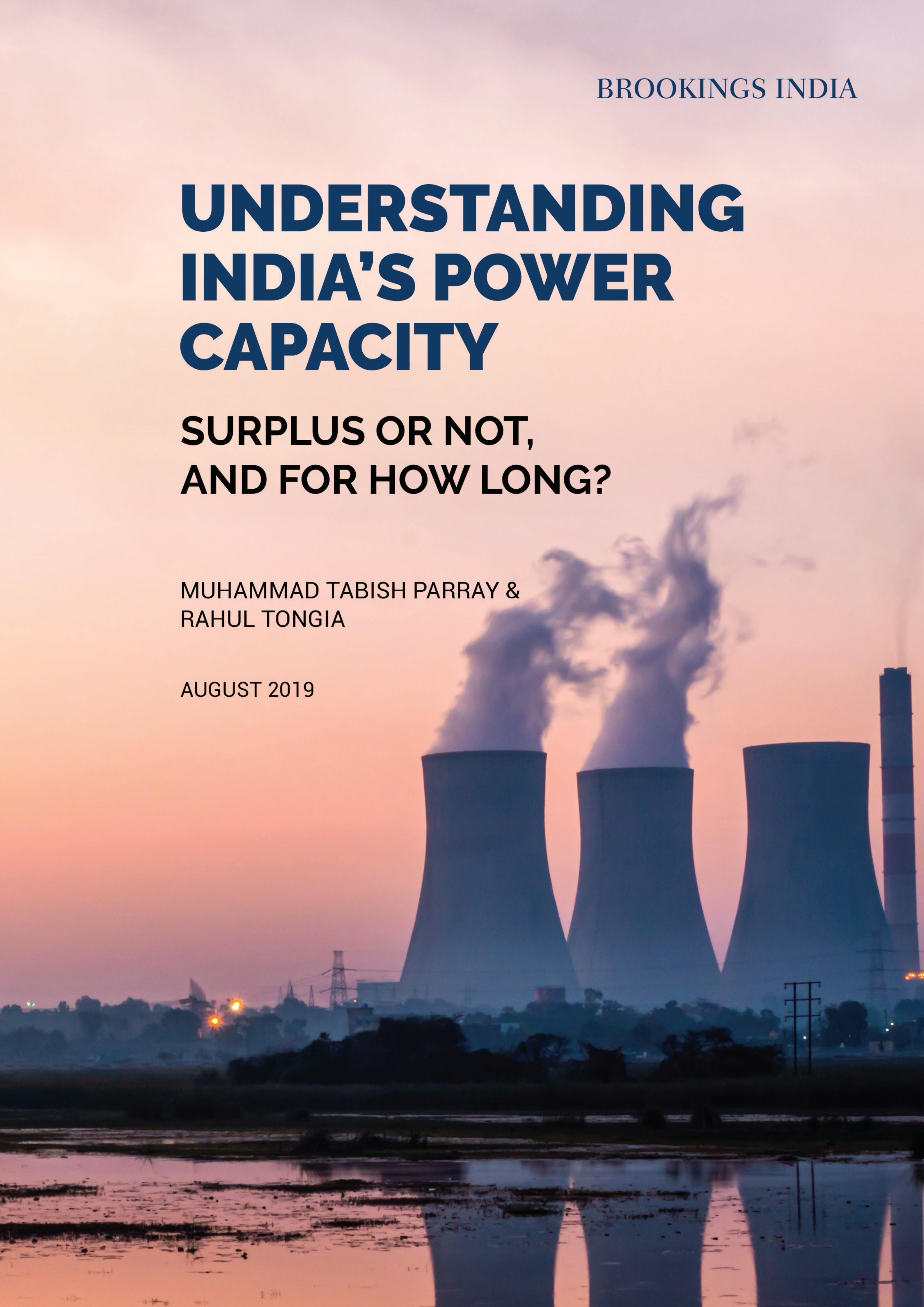

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UNDERSTANDING INDIA'S POWER CAPACITY

SURPLUS OR NOT, AND FOR HOW LONG?

MUHAMMAD TABISH PARRAY &
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AUGUST 2019

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Executive summary

1. India's gross installed capacity is around 349 GW, but peak load met over FY 2018-19 at a grid level has been about 175 GW. For a number of days, the daily peak load met has been measurably lower. This is the supply—*consumption* is far lower, reflecting in-state losses, both transmission and distribution.

2. At the national level, India's peak electricity demand usually occurs in the evening. Meeting this demand requires relatively firm supply which variable Renewable Energy (RE) cannot supply in the absence of storage.

3. Firm capacity outage at any time of the year varies between 60 GW to 90 GW, leaving the available firm capacity between 180 GW to 210 GW. Auxiliary consumption, which is generation consumed within the plant and thus not fed to the grid, varies by type of generation and further reduces the net firm capacity available to meet demand.

4. There are a multitude of factors contributing to outages of capacity, which broadly fit within three types:

    a. Technical issues (faults, planned maintenance, unplanned maintenance, etc.)
    b. No or low demand (too low to be met by a generator in practice)
    c. No fuel availability [There are a few other regulatory and other reasons for outages as well, but (a) to (c) contribute to over 90% of outages.]

5. Approximately 13 GW of firm capacity outage *could* be recovered quickly based on proper planning and co-ordination e.g. by ensuring the availability of coal and gas. This is distinct from low plant load factors (PLFs) of many generators which run at or near the peak demand period.

6. Firm capacity outages vary by season as well as region. For example, outages due to coal shortages were predominant in the Western Regional Load Dispatch Center (WRLDC) all year round and in the Eastern RLDC between October-January (using recent data).

7. Meeting the average requirement of energy (TWh, or billion units, aka BU) will be less of a problem in the future than meeting the requirement of instantaneous capacity (megawatts). RE is growing at a fast pace in India, but based on daily and seasonal differences, and in the long run without storage, it plays a very small (about 3% observed during December 2018)[1] role in meeting the peak demand (which mostly occurs in the evenings).

8. With a growth of nearly 10 GW in peak demand anticipated every year, perhaps more, the current capacity surplus as well as the planned installation of non-coal firm capacity might not be enough to meet the peak demand as early as 2021 or 2022. Some form of additional peak supply would be needed at most by 2022, after exhausting the recoverable outages of about 25 GW (a mix of no fuel and no demand today). Deciding on the best type of generation capacity to meet the peak is a separate calculation. A new coal plant may not be optimal, unless it is well under construction and nearly built, and can operate viably at low or modest PLFs. A better focus will be peakers, storage, demand side management/demand response, load shifting etc.

[1] Based on authors calculations on the Merit India data.

9. 62.7 GW of firm capacity has been planned to be built between 2017-2022, averaging at about 12.5 GW per year. However, for the one-year period between October 2017 and September 2018, only 3 GW of capacity has been commissioned. Unless projects are heavily stacked towards the end (2022), it is highly unlikely that all the planned capacity will be commissioned by that time.

10. One big unknown is compliance with upcoming environmental norms, which will result in downtime for retrofitting existing coal plans, or even retirement of some older capacity. Almost all the planned upgradation of the power plants to meet upcoming environmental requirements is scheduled in 2021-2022. This will lead to many power plants being shut down simultaneously during that period. It would be beneficial if the upgradation schedule is front loaded or at least more evenly distributed between 2019-2022, to reduce the impact of lost capacity to meet peak demand.

11. Future studies should investigate the optimal generation mix required, from the perspectives of true technical economics (distinct from contractual economics), greenhouse gas (GHG) emissions and grid stability in a high RE future. Also, a detailed analysis for the reasons of coal and gas shortages is required, to chart out a reasonable course of action to overcome these. Different Regional Load Dispatch Centres (RLDCs) have different strengths and weaknesses, with some performing better than others when it comes to capacity outages. There is a need to share the best practices among the various RLDCs, and coordinate for planned maintenance, including upgrades to meet environmental norms.

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Introduction

The dichotomy of installed capacity of 350 GW versus an average load met of less than half

India's March 2019 installed electricity capacity (grid-based, that is, excluding captive power and small scale Renewable Energy) was 356.1 GW (CEA, 2019). More capacity is being added to the grid and the country has ambitious Renewable Energy (RE) targets, aiming to install 175 GW of renewables by 2022, out of which 77.64 GW have been installed till March 2019. Solar PV (100 GW) and wind (60 GW) constitute the major components of these targets. In addition to the RE targets, per the Central Electricity Authority (CEA), a total of 62.7 GW firm aka dispatchable Capacity is planned to be built by 2022, whereas 22.7 GW is projected to go offline. Meeting these targets will take the total installed capacity by 2022 to nearly 475 GW.

Compared to the capacity, the peak demand met till date (March 31, 2019) in the FY 2018-2019 was 175.59 GW (met in Sep 2018). This is the load met at the grid level as visible at state boundaries. This figure, like installed capacity above, does not consider (1) captive power and (2) rooftop solar and distributed generation (or other very small generation not visible to the grid SCADA [Supervisory Control and Data Acquisition]). This load met at a grid level, which is higher than consumer load (which is after distribution losses), is only around 50% of the total current installed capacity of 349.29 GW. Thus, if only 50% of the capacity is "utilised" currently, isn't the country vastly in surplus? We examine this question in detail in this paper.

The gap between capacity and load met have many reasons. Peak demand usually occurs during the evening periods when there is no solar present and wind varies heavily. Subtracting the total RE capacity installed (74.08 GW), we are then left with an effective "firm" capacity of 275.2 GW. India quotes gross capacity, so removing auxiliary consumption of about 8% for the power plants, the available installed capacity at busbar comes to 253.2 GW. For generation, location matters. Our understanding is that the "load met" is at state boundaries, meaning for any out-of-state generation, inter-state transmission losses are outside the "load met" or "demand met" figure. On the other hand, in-state generation (busbar) is captured in full. This is one reason the sum of generation versus load met at a grid level differs in official data, as visible on the real-time grid online portal MERIT (http://meritindia.in).

Importantly, the installed capacity has certain constraints when meeting demand requirements. Considering that a percentage of this capacity will be under maintenance, refurbishments, technical faults etc., we realise that there isn't much margin left.

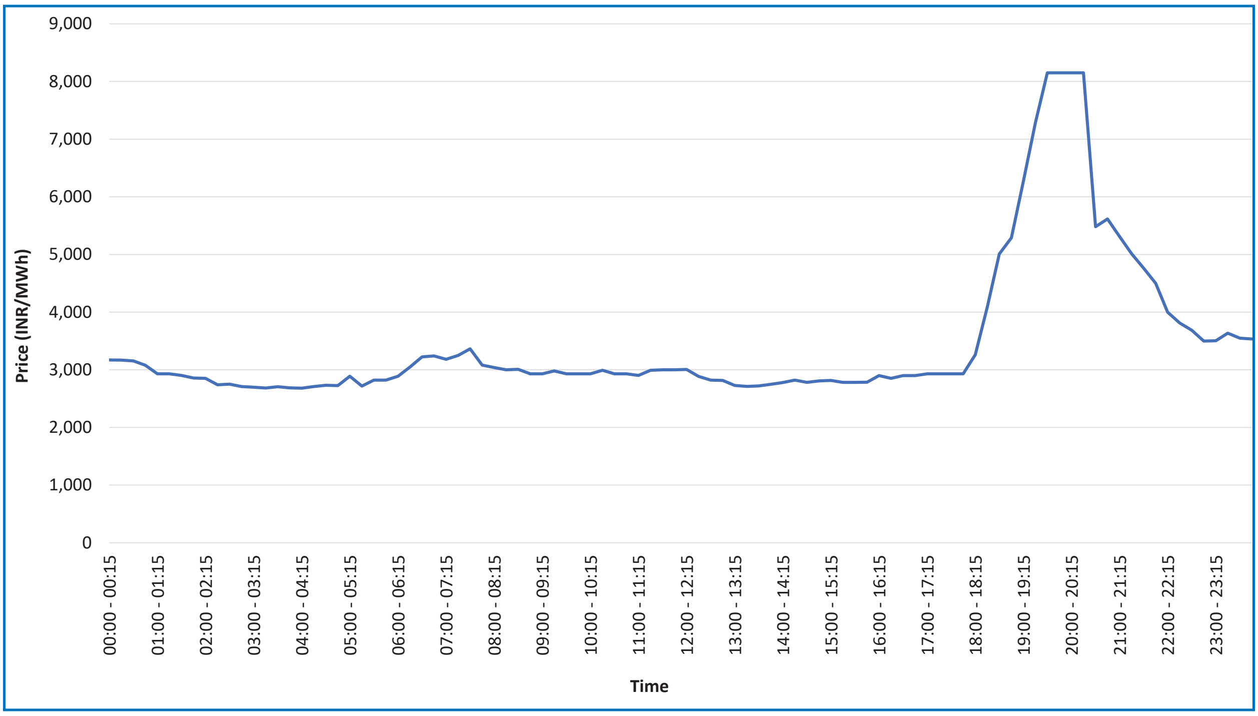
What part of our capacity is under outage? What part can be recovered? What part cannot be recovered? How much capacity surplus do we have? How long will it last? We attempt to address these questions in this paper and develop an understanding of how much future growth can be handled with the current capacity. We utilise grid data from Power System Operation Corporation Limited (POSOCO) and other sources including Central Electricity Authority of India (CEA) to study all these issues and arrive at scenarios of how much surplus India has, and how long it may last.

The present scenario

The high variability of RE, coupled with the higher Renewable Purchase Obligation (RPO) has consequences for grid capacity. Many despatchable power plants (thermal) are on Reserve Shut Down (RSD), ready to supply load when the demand increases or when the generation of RE decreases. The government increased Renewable Purchase Obligation (RPO) targets from 17% in 2018-19 to 21% in 2010-22 (Government of India, Ministry of Power, 2018). The disproportional rise of RE output indicates a risk of more plants being *shut down* based on *net demand* (post-RE). Such plant shut downs are deemed outages, and differ from reduced outputs of thermal plants, measured by a fall in Plant Load Factor (PLF).[2]

We also have a strong evening peak, both shown by aggregate demand (load meet) as per Daily Reports by NLDC (POSOCO, 2018), as well as market clearing prices from the India Energy Exchange (IEX, the power exchange), which reflect not just demand but supply conditions (Singh, 2018) (Shreya Jai, 2018). As Figure 1 illustrates, while the load profile of India has a quasi-mid-day peak as well, the market shows spikes in the evening, likely reflective of RE's output in the day. This is one reason granular breakdown of supply by type of generator is important for analysis and planning.

Figure 1: Market Clearing Price (MCP) at India Energy Exchange (IEX) on a representative day (Sep 5, 2018)



Note: Although the above graph contains data for all 15 min time blocks, the x-axis shows only the first time block for each, due to space constraints.

Outages on the grid thus depend not just on plant conditions but on grid conditions, which are a combination of demand as well as what else is able to supply. High RE for the same level of demand can mean more outages under RSD conditions. Of course, RE varies by time of day as well as season.

[2] A lower output, measured via Plant Load Factor (PLF), impacts power plant efficiency, but start-stop operations also consume significant energy, and impact plant lifespan and O&M. Demand based outages are officially split into "no demand" and reserve shut down (RSD) – the latter where there is some demand, but it is too low to run the plant.

Analysis of supply and demand

Data limitations

Various government organisations like POSOCO (under its arms NLDC and RLDCs) and CEA have large volumes of data in the public domain. The data is usually in the form of daily, weekly, monthly and annual reports. However, the electricity demand, supply and generation mix (renewables variability) varies every second and the changes can be large over a small interval of time. Thus, a higher resolution data (intraday data) would be ideal to perform a deep dive analysis of the generation capacity available and how the variation in demand effects the same. As high-resolution time-of-day data is not available under daily reports, we can only draw limited insights from the data available. This is one reason we examine daily data and use outages as defined as a generator being under outage for the entire day. This avoids time of day issues (partial outages).

Rise of peak demand

While full data are unavailable publicly, NLDC releases some data on peak demands, and this has changed over time. For six years, daily reports list evening peak demand.

Over the past five years, the evening peak demand has continuously risen. Table 1 below shows the year-over-year increase in the evening peak demand met. The evening peak demand over the past five years has been going at average of 5.28% per annum (CAGR).

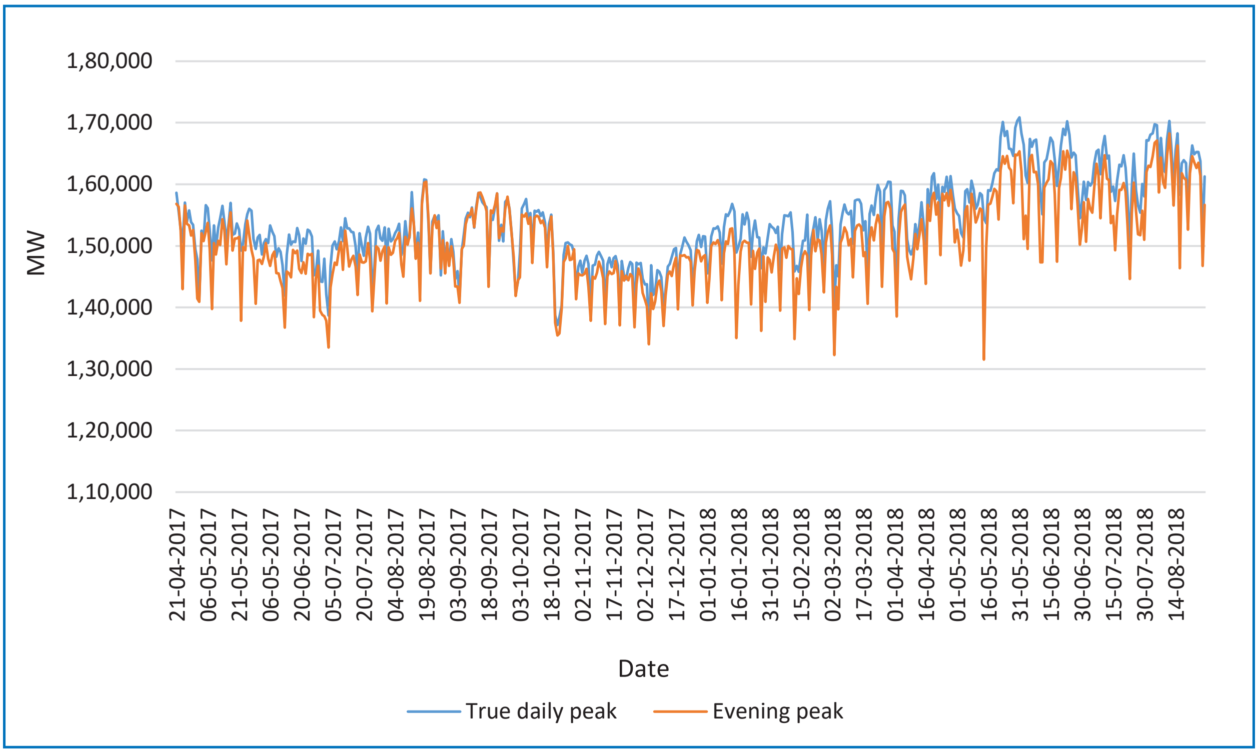
Table 1: Year on year increase of evening peak demand met

Year	Highest Evening Peak Demand	YOY Growth
13-14	128,251	–
14-15	138,215	7.21%
15-16	147,655	6.39%
16-17	156,058	5.38%
17-18	160,407	2.71%
18-19	174,682	8.89%

Source: Calculated from Daily Reports and authors calculations Power System Operation Corporation India, (2014-2018)

The true daily peak demand is higher than the evening peak demand[3] in majority of the cases, as can be seen from the POSOCO daily reports since 2017 (when the true daily peak demand data has become available). Figure 2 below shows how the true daily peak varies with respect to the evening peak.

Figure 2: True daily peak demand vs notified "evening peak" demand (May 7, 2018 – Aug 28, 2018)



Note: 1. Evening peaks are the demand at a fixed evening time, either 7 pm or 8 pm as chosen for calculations by the grid operator. The true daily peak could still be in the evening, as it happens on most days.

2. The Y axis starts at 110,000. This has been done to highlight the differences between the absolute and evening peaks.

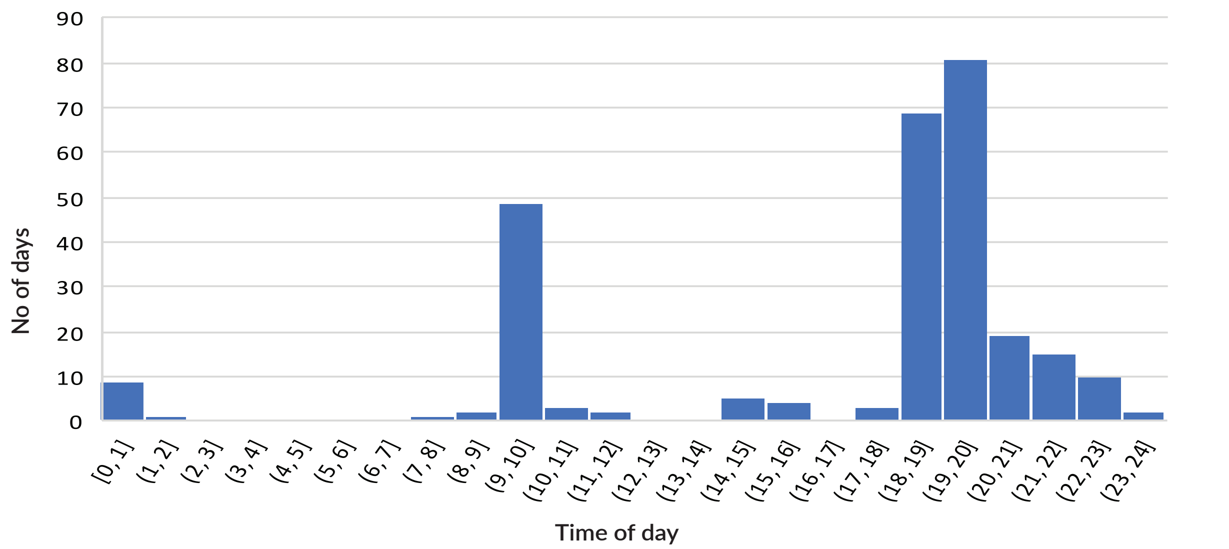
We observe that the true daily peak demand is higher than the evening peak demand on most days as shown in Figure 2. While these data points are not enough for a trend analysis, we see visually that the spread between absolute and evening peak is slightly increasing. Regardless, for our calculations, let us assume they are similar.

The time at which the true daily peak demand occurs is important and will determine the type of generation resources required to cater to the demand. In Figure 3, we observe that most of the true daily peaks occur in the evenings between 6 pm-8 pm. Although solar installed capacity is supposed to increase to 100 GW by 2022, without a viable storage option, the contribution of solar towards this peak will be effectively zero. In the future, a higher installed solar capacity could also lead to higher ramping in the evenings, as the ramp not only has to cater to the increase in demand, but also the decrease in solar output.

[3] The true daily peak demand refers to the highest demand on the given date. The evening peak demand refers to the demand that is there at 19.00 hours or 20.00 hours as referred to in the POSOCO daily reports. These include data up to December 31, 2018. This translates to a CAGR of 5.28% between 13-14 and 18-19 for the evening peak demand.

On some days (about 15% of the days), the peak also occurs in the mornings between 9 am-10 am, and for these days, solar could contribute more towards the peak. However, if these dates are in the winter, due to issues of fog and pollution, the contribution of solar might be lower than in other months.

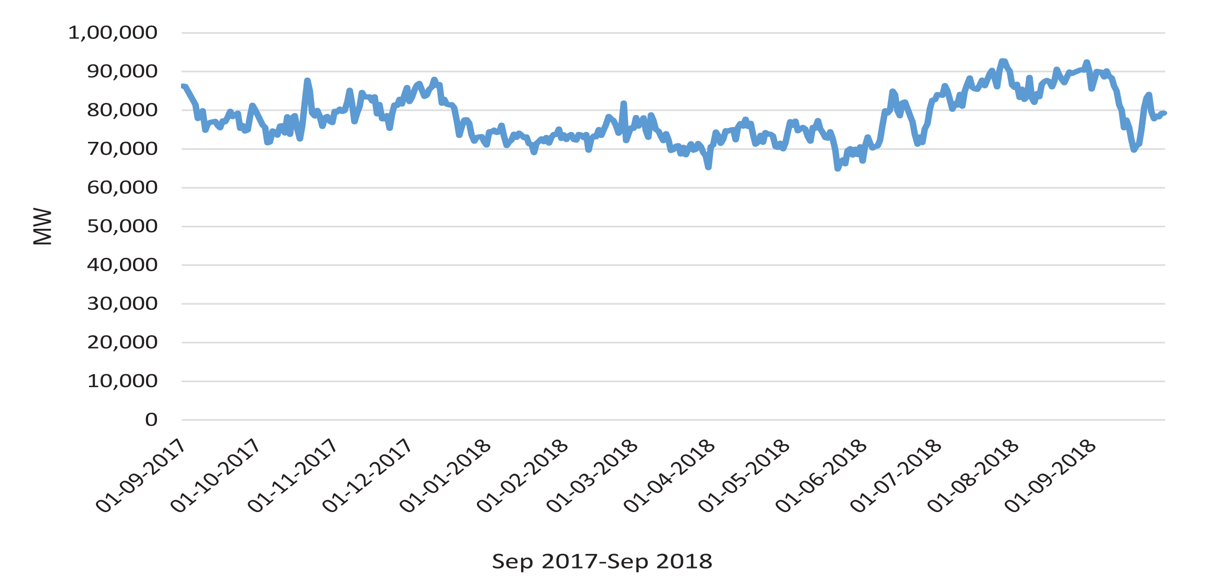
Figure 3: Frequency of true daily peak demand (01 May 2018 – 12 Feb 2019)



Methodology

For the purpose of our analysis, we examined generator outages over a period of one year. We began with CEA daily reports as shown in Figure 4. However, on closer inspection, we found that the reasons for many outages are missing in the CEA daily reports. The RLDC daily reports on the other hand, mention all the outage reasons for the daily outages.[4]

Figure 4: Daily capacity outages between (Sep 2017-Sep 2018)



Source: Calculation based on the CEA daily reports data as compiled by Shayak Sengupta

[4] There is also a discrepancy between the outages reported in the CEA daily reports and the NLDC reports, with CEA reports consistently reporting higher outages.

To better understand the various reasons for the outages, we closely examine capacity outages for 12 representative weekdays (non-holidays) spread over 2018 (one from each month), with different RE generation. We do not examine all the days as we are not focusing on the average number; rather, our interest lies in examining the indicative *ranges* for outages. In addition to data availability challenges, this methodology should not impact our findings because we are not attempting to provide a statistical analysis of the outages, but rather ranges for the outages. The existence of a particular level of outages is what we use for further analysis, since we examine the possible shortfalls between supply and demand, as opposed to the expected value.

The data has been chosen for the four RLDCs, namely NRLDC, WRLDC, SRLDC and ERLDC from their respective websites. NERLDC (Northeast RLDC) has not been included due to unavailability of the data. Henceforth, whenever the RLDCs are referred to in this paper, it will be referring to all RLDCs excluding NERLDC, which is a small fraction of India's load (around 1.6%). Table 2 below shows the total capacity outage on 12 weekdays in 2018 (National Power Portal, 2018).

Table 2: Capacity outages on selected dates in 2018 for the RLDCs

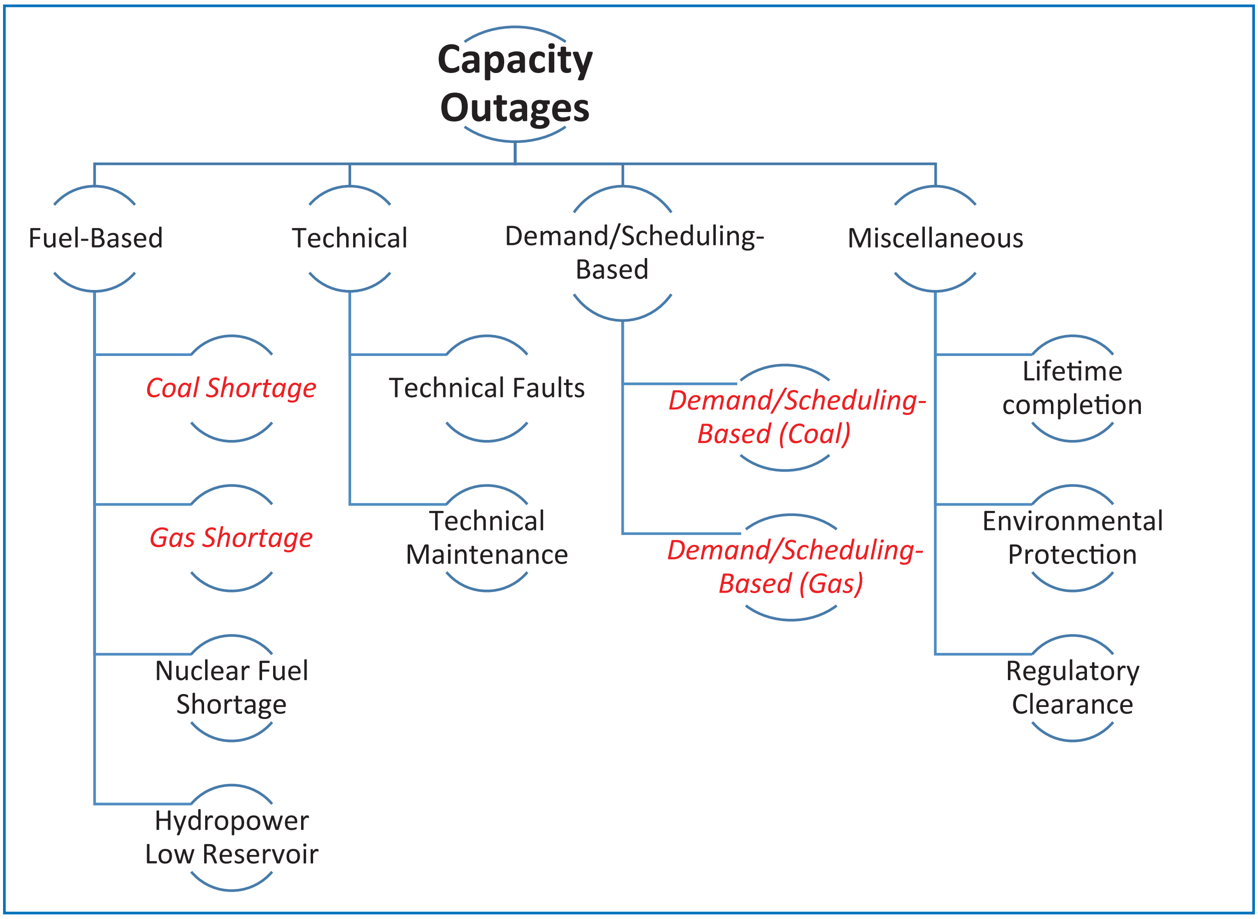
Date	Total non-RE capacity of the RLDCs	Capacity outage	Capacity outage as percentage of total non-RE capacity
05-01-2018	266,787	64,976	24.4%
06-02-2018	267,637	61,789	23.1%
05-03-2018	267,384	65,560	24.5%
03-04-2018	271,294	60,170	22.2%
08-05-2018	271,174	60,966	22.5%
05-06-2018	271,174	57,769	21.3%
05-07-2018	271,174	71,193	26.3%
07-08-2018	271,174	78,022	28.8%
05-09-2018	270,314	78,516	29.0%
09-10-2018	270,344	59,803	22.1%
05-11-2018	270,419	66,513	24.6%
04-12-2018	274,016	65,908	24.1%

Source: Total non-RE capacity is from the CEA Monthly Reports

Note: Capacity outage has been calculated from the Daily Outage Reports of the various RLDCs. Reported outages do not include any outages in the solar and/or wind power plants due to technical faults, curtailment, or otherwise. However, there is a discrepancy of an average of 10 GW between the total outages mentioned in the RLDCs and the CEA Daily Outage Reports, with CEA data consistently reporting higher outages. We are using RLDC data for our analysis, as the reasons for outages are always mentioned in these reports, whereas same is not the case with the CEA Daily Outage Reports.

The different capacity outages have been categorised as shown in Figure 5.

Figure 5: Different types of capacity outages



Note: Shown in red and italics are outage reasons that might be "recoverable" in the future, based on rising demand and improved fuel availability.

For the purposes of this analysis, we consider only a subset (in red) to be recoverable outages. In theory, some of the faults, especially unscheduled equipment faults could be reduced based on improved maintenance, but we do not consider those here.[5]

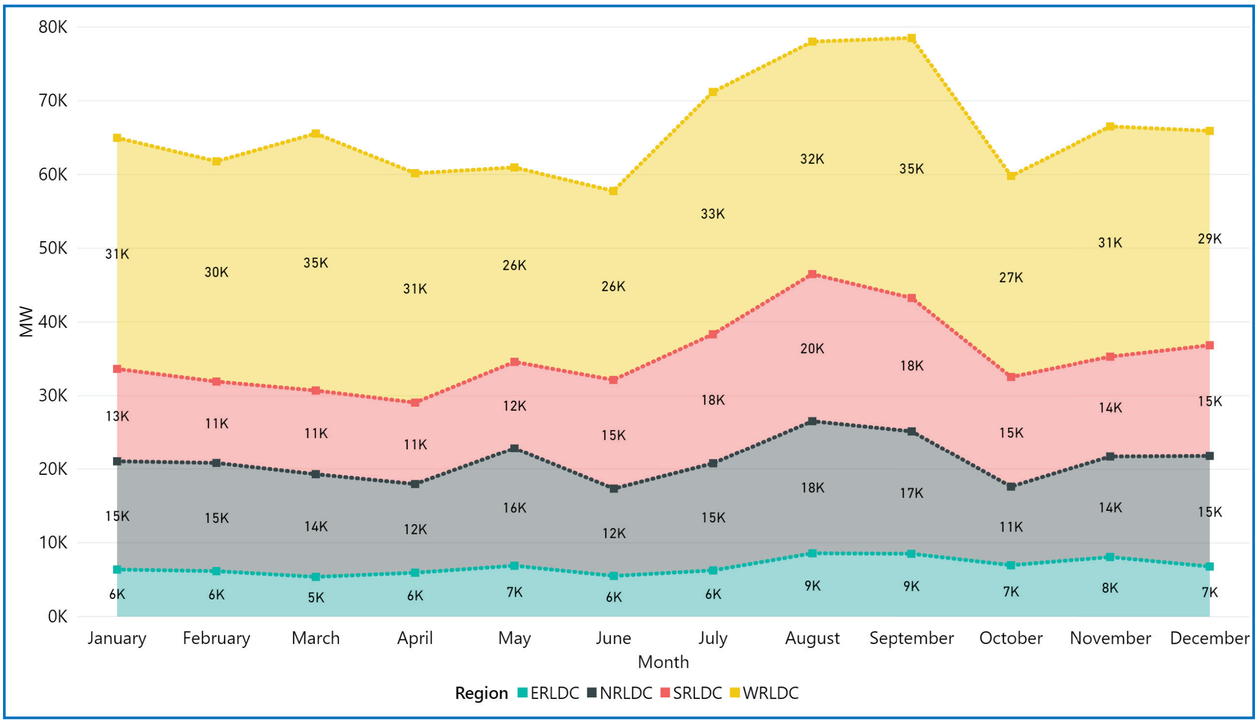
[5] Although Nuclear Fuel Shortage should also be considered as recoverable, it was present for only a few days in a year and the outage capacity was comparatively insignificant. It is also less likely to be easily recoverable with market approaches like lack of coal or gas could be.

Observations on outages

Regional variance of outages

The capacity outages vary between the various regions as shown in Figure 6.

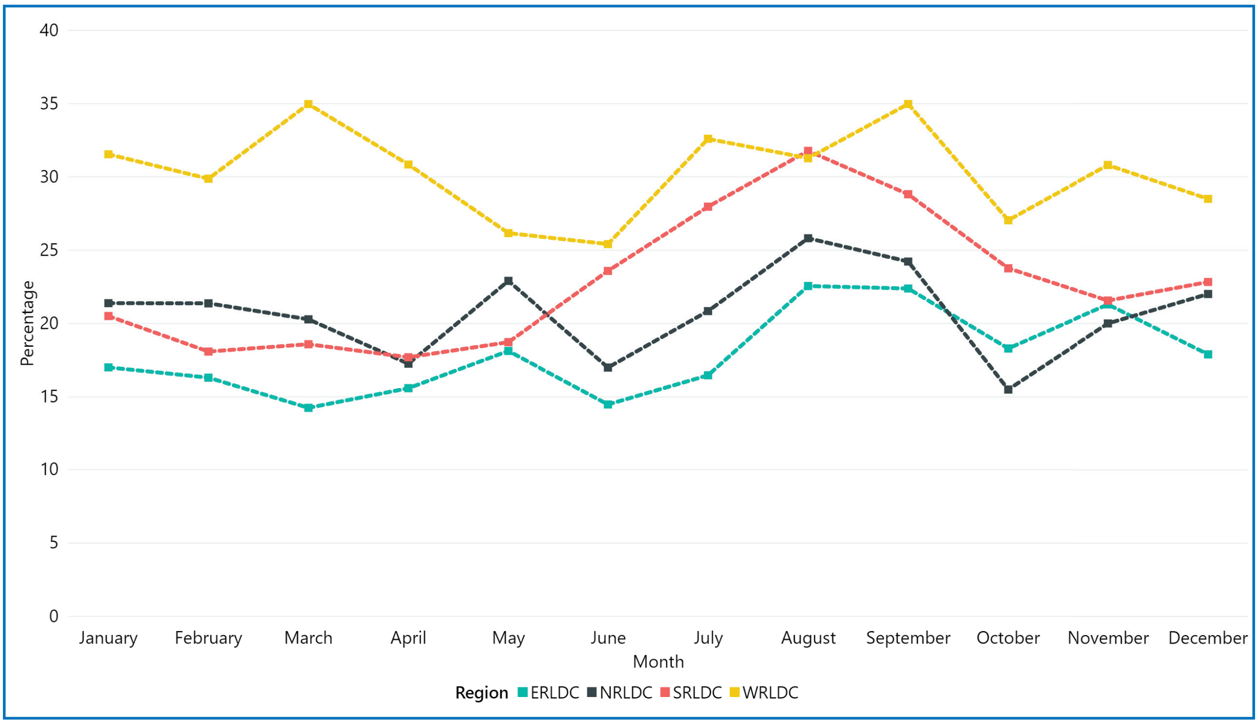
Figure 6: Region-wise capacity outages for the selected dates



Note: The month in the above figure refers to a single selected day from that month (Table 2), and not the entire month. Data are missing for NERLDC, but this region is only 1.6% of Indian load.

Region-wise, the western region has the highest outages and the eastern region has the lowest. However, these regions also have the highest and lowest installed conventional generation capacities respectively. To develop a better understanding, Figure 7 shows the capacity outage as a percentage of the total installed capacity in the region, which shows a slight reduction in spread across regions.

Figure 7: Region-wise percentage capacity outage for the selected dates



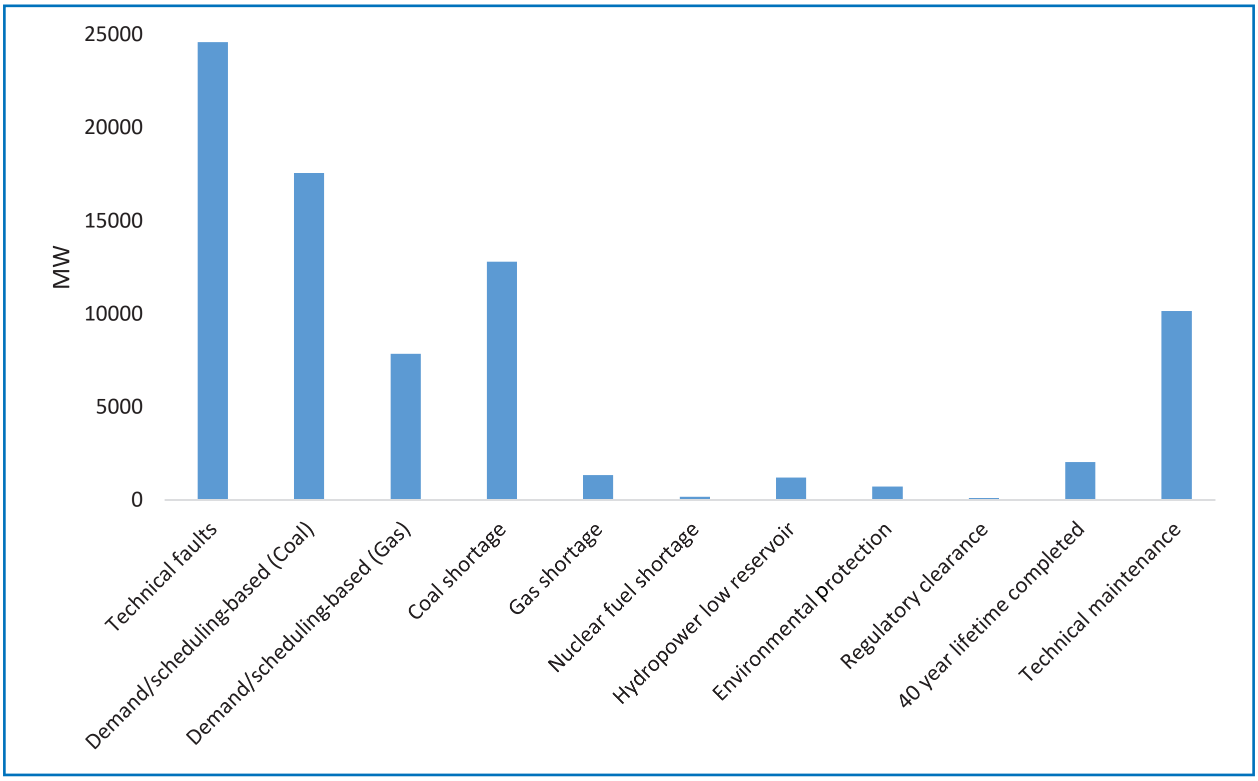
Note: The month in the above figure refers to a single selected day from that month, and not the entire month.

We observe that the western region also has the highest percentage of capacity outage. The outages in the southern region are also higher in the second half of the year. This is due to several factors, including the generation mix in these regions. For example, the western region has a higher amount of gas power plants, and gas being expensive, the plants in this region are dispatched later in the Merit Order. As the gas power plants have a higher chance of being in RSD (Reserve Shut Down, a form of "low demand"), the capacity outage of these regions increases. Similarly, in the southern region, wind increases in the latter half-of-the-year with the onset of monsoons. However, a more detailed study is required to ascertain the various reasons (seasonality, efficiency, generation mix) for the large percentage differences in capacity outages among these regions.

Some outages are larger than others

The various outages outlined in Figure 5 contribute in different proportions towards the total capacity outage. To illustrate the point, Figure 8 shows the contribution of the various capacity outages on September 5, 2018. A similar analysis of the reasons for breakdown of thermal capacity outages from 2013-2016 has been carried out by World Resources Institute (Tianyi Luo, 2018).

Figure 8: Contributors to capacity outage (snapshot for Sep 5, 2018)



Similar contribution towards the total capacity outage has been found for other days too. We observe for this illustrative day that the majority of the capacity outage is caused by the following reasons:

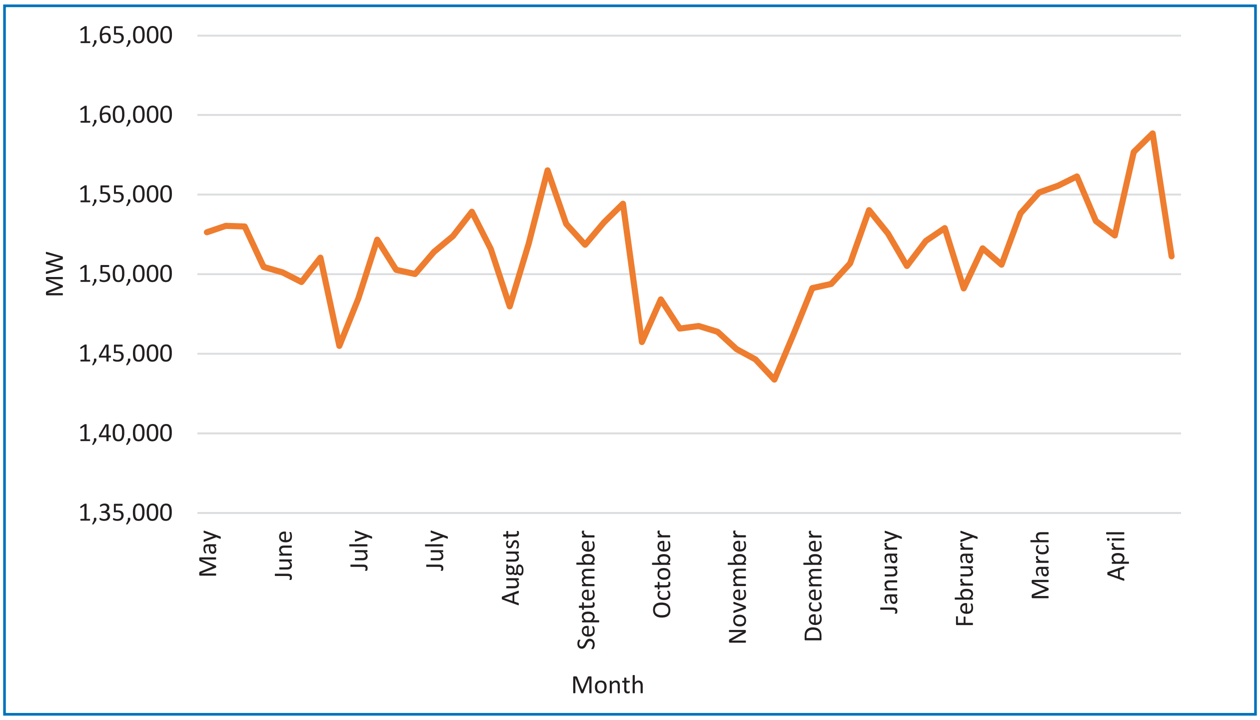
1. Technical maintenance (12.9%)
2. Technical faults (31.3%)
3. 40-year lifetime completed (2.57%)
4. Gas shortage shutdown (1.7%)
5. Coal shortage shutdown (16.3%)
6. Demand-based (Gas) (9.99%)
7. Demand-based (Coal) (22.3%)

The percentages turn out to be less important given we are focusing on the existence of recoverable capacity (last four categories). Demand based outages are the easiest to be recovered as and when the demand increases.

Temporal variance of outages

Seasonality is an important factor when it comes to capacity outage. Demand of electricity as well as the generation from renewables varies depending on the season, thereby directly affecting the capacity outage. The graph below shows the weekly average peak demand from April 2017- May 2018. We observe how the peak demand is higher in the summer season and dips during the monsoon and the winter seasons.

Figure 9: Daily peak demand (averaged per week) (May 2017-April 2018)

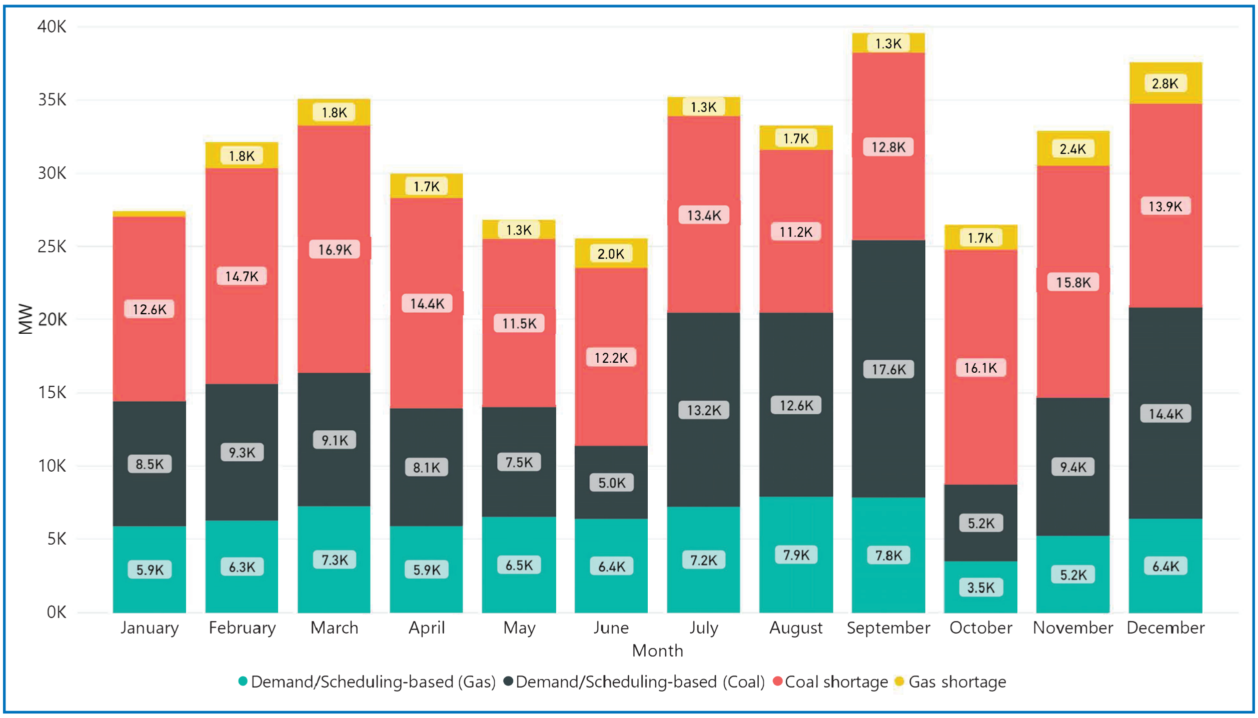


Note: The weekly average peak demand (load met) has been shown, to smoothen the effect of lower demand on weekends.

Source: Authors' calculations on POSOCO Daily Reports

Figure 10 shows the different types of recoverable capacity outages for the selected days. The combined coal shortage and gas shortage outage varies between 12 GW to 18 GW, depending on the time of year. This shortage can be due to logistical, contractual or other issues and with proper measures this generation can be brought online. The deficiency in coal can also be met with import of coal from other regions and/or countries and is already happening[6] (The Economic Times, 2018). Similarly, the demand/scheduling based outage also varies between 8,700 MW to 25,300 MW over the year.

Figure 10: Different types of recoverable outages



Note: The month in the above figure refers to a single chosen day from that month, and not the entire month.

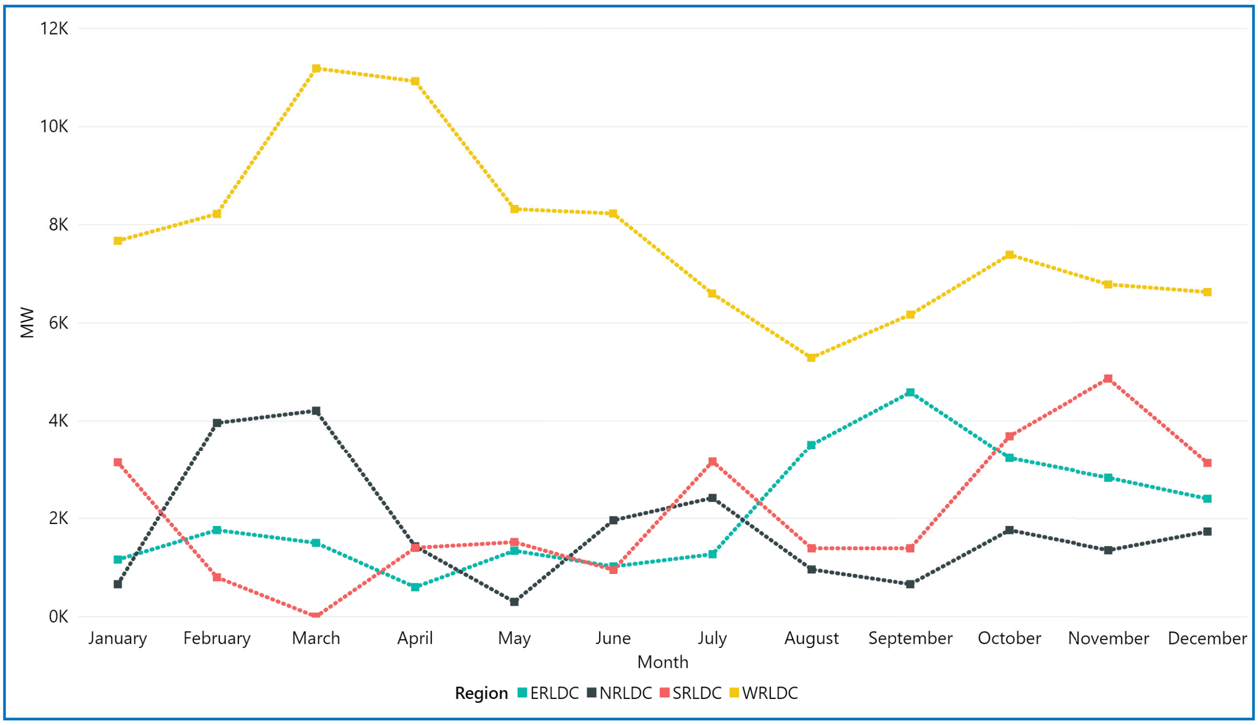
However, it is important to recognise that recoverable capacity doesn't equal the sum of the recoverable components in the short run. Even if we had fuel available, *until* demand rises, it would simply shift the outage from no fuel to no/low demand (RSD). Assuming both constraints (fuel and demand) are overcome, we then may have upto 25 GW of recoverable capacity.

[6] From 16-17 to 17-18, the non-coking and coking coal imports have increased from 18.1 million tons and 5.3 million tons to 22.5 million tons and 7.7 million tons respectively. This translates to an increase of 24.4% and 45.67%.

Coal shortage as a major outage contributor

Coal shortage is one of the major contributors to the recoverable capacity outage. Figure 11 shows how the coal shortage varies regionally. We see that the western region faces the highest capacity outages due to coal shortages.

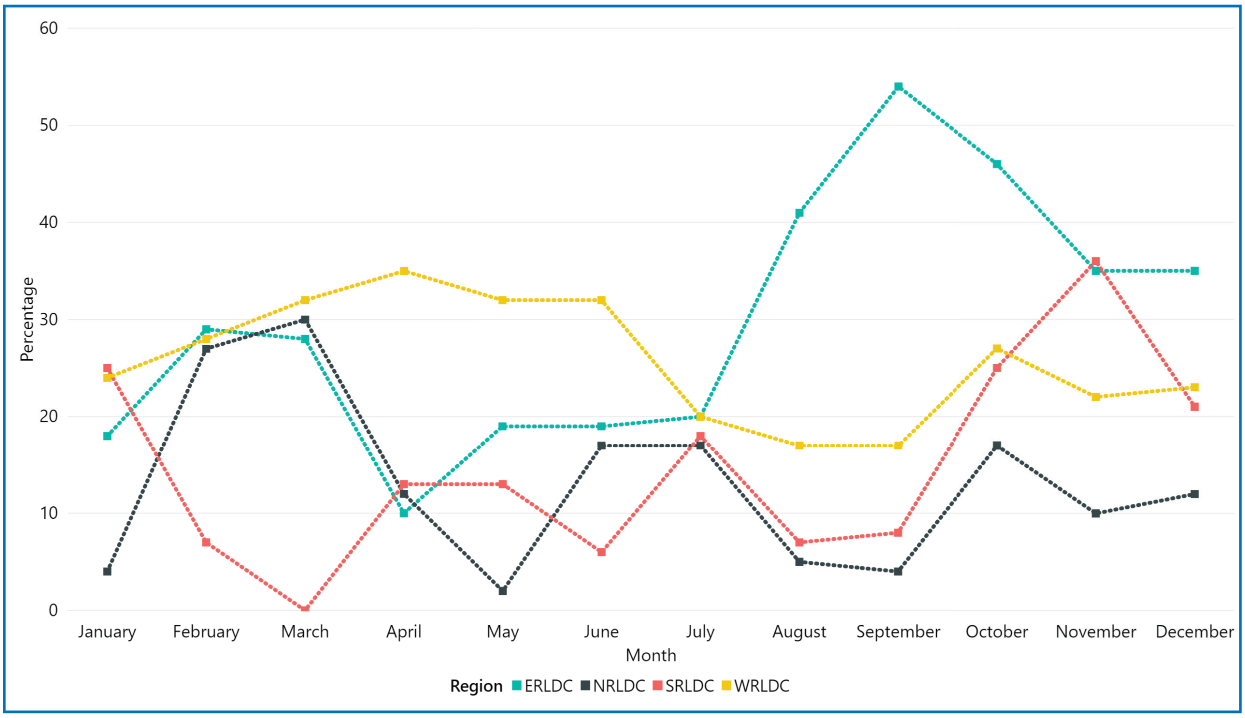
Figure 11: Outage due to coal shortage in 2018



Note: The month in the above Figure refers to a representative selected weekday from that month, and not the entire month.

On a percentage basis, coal shortages contribute between 17%-35% of the total capacity outages in the western region as shown in Figure 12.

Figure 12: Coal shortage as percentage of total capacity outages



Note: The month in the above figure refers to a single selected day from that month, and not the entire month.

Surprisingly, in the eastern region, coal shortages contribute between 10%-54% of the total capacity outage, despite being a region rich in coal deposits. The range of variation is very large and demands a separate study into the various reasons for such phenomenon.

Key findings from 2018 outage data analysis

1. Recoverable capacity varies between 25 and 40 GW.
2. Peak demand, overwhelmingly in the evening, grew at a CAGR of 5.28% between FY 13-14 to FY 18-19 (till date).

By focusing on the peak for a day, and outages at a day level, issues of PLF become moot – a plant was either producing in the day or not producing, and hence, if it comes online, we can assume it would offer power at the peak period. This contrasts with a PLF-based analysis, where, for example., if one finds a fall in PLF from 70% to 60% for a power plant, this may not help meet the peak demand as it may still be producing at capacity during the peak period; without ToD outputs we don't know for sure, but we would estimate so.

Estimating online capacity and future sufficiency

There is a modest "surplus" in the grid today, which varies based on demand and availability of RE. This would also change in the future based on any shifts in load shapes. In this section, we project how long the "recoverable" capacity can suffice based on projections for future growth of the load, measured at the peak.

To project ability to meet load in the future, the factors that matter will be:

1. Recoverable capacity.
2. Available capacity in the future.
    a. New capacity.
    b. Existing capacity reductions (factoring in retirements, refurbishments, environmental norms compliance, etc.).
3. Demand growth rates, especially with time of day considerations.

The "recoverable" capacity is a complex issue that we cannot easily measure, in part because the past may not be a predictor of the future. More importantly, our objective is to understand how much future growth can be handled with existing capacity. As we don't have time of day data on load, it's difficult to determine the exact interplay between demand, net demand (post RE), and outages. It's not unusual for many thermal plants to plan annual maintenance during a high RE season. Thus, using the data on outages, we undertake parametric analysis with wide uncertainty, to examine future ability to meet load.

Future demand for electricity

Electricity demand (including captive demand) is expected to grow at a CAGR of 5.4-7.4% (Ali, 2018) through 2030 under a range of assumptions of GDP growth and energy efficiency. A mid value is 6.2% CAGR. The same study projects non-captive electricity demand, i.e., grid demand, to grow at a lower rate than this. In this study, we parametrically assume three different growth rates (5%, 6% and 7%) to calculate how the peak demand will look in future. Table 3 below shows how the peak demand will grow (till 2022) for the three growth rates, with the year 18-19 *thus far* as the base year.

Table 3: Peak demand (in MW) for different growth rates

Year	Growth (5%)	Growth (6%)	Growth (7%)
18-19 base	175,590	175,590	175,590
19-20	184,370	186,125	187,881
20-21	193,588	197,293	201,033
21-22	203,267	209,130	215,105

Source: Authors' calculations based on POSOCO Daily Reports

The growth of demand will depend on several factors, not just GDP growth and efficiency of end-use consumptions, but also policy decisions of the government regarding CO_2 emissions, new building codes, growth of industry, electric vehicles etc. However, for the short-term future (till 2022), the following factors will affect electricity demand – these are already factored in the analysis by Mohd. Sahil Ali:

1. *Electrification*: As of January 30, 2019, around 29,000 households in India don't have access to electricity (Ministry of Power, 2019). Since October 2017, around 24.8 million unelectrified households have been connected to the grid. It is only a matter of time before all homes at least have a wire. As access to electricity is ensured, there will be a further increase in the demand for electricity by newly electrified consumers. While their overall load may be modest, whatever they do use may be concentrated in the evening, starting with lighting but also extending to other loads.

2. *Lowering/eradication of load shedding*: From the POSOCO data matching chosen dates for outage data, shown in Table 4 below, the load shedding varies daily but within a narrow and small range. A more regional or state basis might provide a different story, as most of the reported load shedding is occurring in a few states. We observe that on an aggregate national basis, however, it is a small percentage. As such, on a national basis, the ability to meet the demand with zero load-shedding should not be a significant burden.

Table 4: All India peak shortage

Date	Demand Met (MW) during Evening Peak (19.00 pm)	Peak Shortage (MW)	Shortage Percentage of Peak Demand (%)
05-01-2018	150,910	1,716	1.14
06-02-2018	149,522	721	0.48
05-03-2018	150,502	723	0.48
03-04-2018	151,121	978	0.64
08-05-2018	158,468	1,076	0.67
05-06-2018	164,145	1,082	0.65
05-07-2018	159,538	650	0.41
07-08-2018	164,329	1,251	0.76
05-09-2018	164,234	1,580	0.96
09-10-2018	168,623	2,831	1.68
05-11-2018	151,160	1,238	0.82
04-12-2018	150,581	544	0.36

Source: POSOCO (2018)

Note: We have a simultaneous shortfall of peak demand via "load shedding" meaning brownouts, and yet plants offline due to low demand. This emphasises the economic and Discom operational aspects in meeting consumer demand.

There is also reason to believe that load shedding might be higher than officially reported. With recent elections, the demand for electricity by the states likely increased in order to ensure round-the-clock supply (Shreya Jai, 2018). This points to the presence of latent demand and evidence of unreported load shedding.

As (Tongia, 2014) had observed, CEA's methodology for calculating shortfall in the Load Generation Balancing Reports (LGBR) is based on supply and demand on a monthly basis with different times for each. Table 4 shows how the shortfall is higher than officially claimed if we not only use the same time period for supply and demand but also tighten it to daily data. In fact, real-time data may be more accurate, something that will require instrumentation. Proposed Amendments to the EA2003 aim to penalise shortfalls of power. Ending load shedding would utilise some of the surplus capacity, but the quantum is small, and we haven't included any explicit shift in demand calculations. Unless there is a dramatic one-time shift, recent historical trend-lines for demand already reflect a steady reduction in shortfalls.

3. *Changes in demand patterns*: If the demand grows in the day, added solar power will be able to meet at least some of this demand. However, if the demand grows more in the evenings, where most of the peak loads occur presently, then more firm capacity addition will be required. The growth of air conditioning in residential vs commercial will play an important role in determining the direction of this growth. Also, the shift of agricultural load from night to day will play an important role in determining the growth of peak demand, for example, through solar pumpsets or solar agricultural feeders. However, even if we assume all the shiftable loads move to mid-day to match solar availability, this does not affect the evening peak, which may not even be the day's True Daily Peak anymore, but it still grows mostly along the lines as projected. Thus, this remains our marker for examining firm or despatchable capacity.[7]

Changes in capacity

The growth in demand will be met by the present surplus capacity and new capacity being built. Below we examine various facets that will affect supply.

1. *Upcoming firm capacity changes*: By the year 2022 new firm capacity is projected to be added, and other conventional capacity phased out. The planned capacity addition and removal by 2022 is quantified in Table 5 below.

Table 5: Capacity addition and removal by 2022

Generation Technology	New Capacity Coming Online by 2022 (MW)	Old Capacity Going Offline by 2022 (Environmental/Lifetime)
Hydro	6,822.50	0
Thermal	47,855.00	22,715.50
Gas	406.15	0
Nuclear	3,300.00	0
Import from Bhutan	4,356.00	0
Total	62,739.65	22,715.50

Source: Central Electricity Authority (2018)

India could thus have a net addition of 40,024 MW firm capacity.[8] As such, the total firm generation capacity will increase from 274 GW (Sep 2018) to 316.4 GW.

As we see in this plan, by 2022, only 402 MW of gas is being added according to the National Electricity Plan (Central Electricity Authority, 2018). The major capacity addition to cater the peak demand and ramping is thus hydro, with an addition of 6822 MW. The import from Bhutan (Hydro)

[7] In theory, there should be little or no agricultural supply during 6-10 PM, or whatever Regulator defined Evening Peak periods are. This is another reason solar pumpsets will not impact the evening peak.

[8] Additional to the 62.7 GW planned installation, there is an uncertainty regarding further upcoming capacity of 12.6 GW. In our analysis, this capacity has not been considered.

takes the equivalent added hydro capacity to 11,178 MW. In the best-case scenario, assuming all the planned hydro and gas is added by 2022, the equivalent additional capacity (hydro + gas) to cater to peak demand is 11,580 MW.

However, with 62.7 GW of capacity to be built by FY2022, starting from FY2017, the yearly target comes to a little over 12.5 GW. From the NPP Monthly Installed Capacity Reports, we find that between Oct 2017-Sep 2018, the firm capacity addition was around 3 GW, as shown in the table below.

Table 6: Firm generation capacity built between Oct 2017–Sep 2018

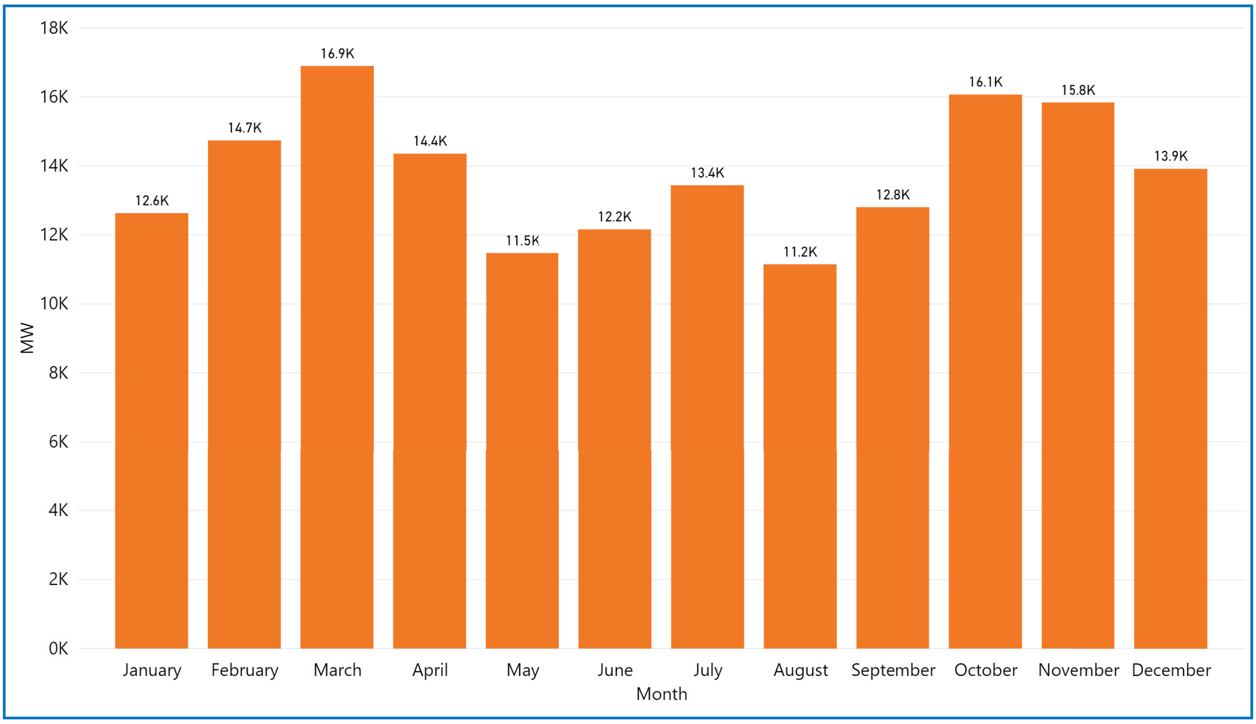
Year	Thermal	Nuclear	Hydropower	Total
Oct-2017	219,449	6,780	44,776	271,005
Sep-2018	221,802	6,780	45,487	274,069
Growth	2,353	0	711	3,064

Source: National Power Portal (2018)

As only around 3 GW of the capacity has been commissioned in this one-year time, it is highly unlikely that the target of 62.7 GW will be reached at this pace. However, it can also be the case that the project completion is heavily stacked towards the end. On the other hand, existing "surplus" is likely signaling a slowdown in completion of planned projects – it is possible some may not be built (and perhaps should not be built), at least in the projected timeframe.

2. *Coal supply position:* Currently the capacity outage due to coal shortage is anywhere between 12 GW to 16 GW, as shown in Figure 13.

Figure 13: Coal shortage shutdown in selected days of the month

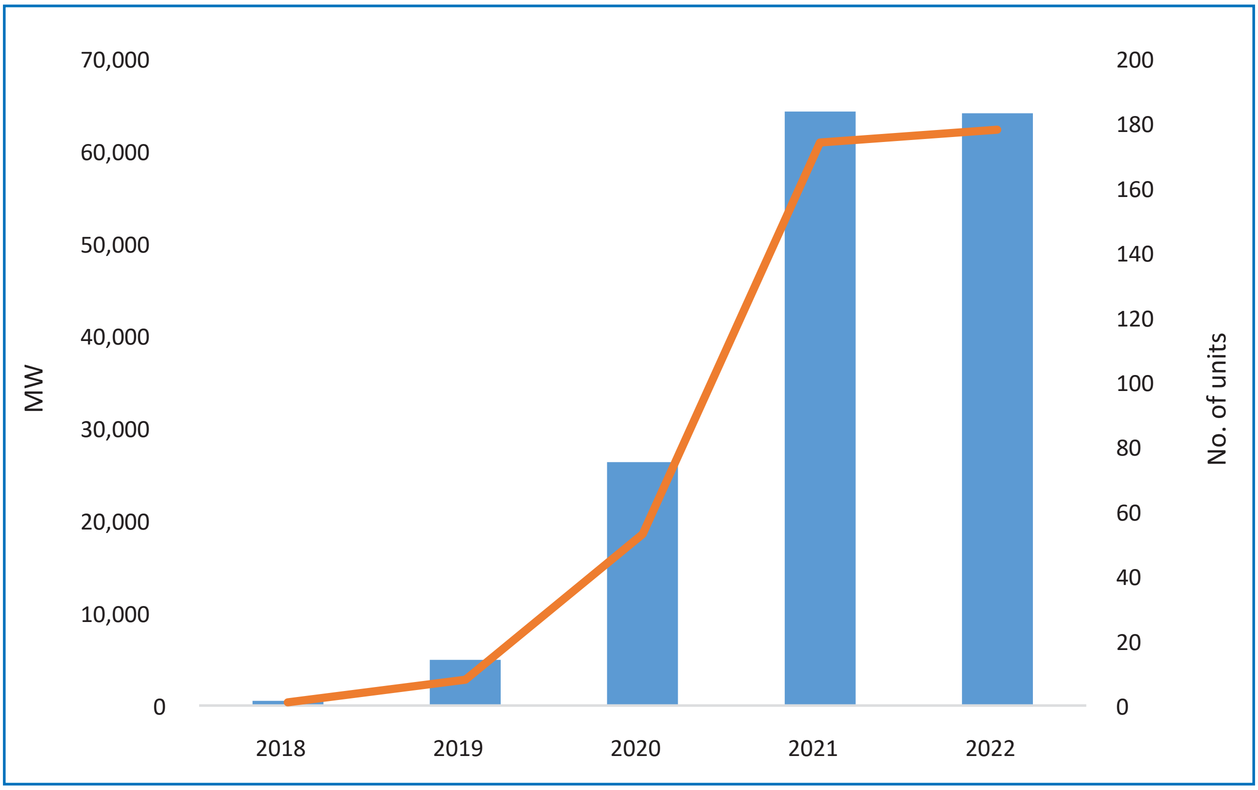


Note: The month in the above figure refers to a single selected day from that month, and not the entire month.

This is after the government prioritising the power sector for delivery of coal, and imports not coming down as envisaged (See footnote 6 above). Pricing, taxation, and environmental controls will determine coal's price, which will also impact its availability and source (including imports). As the share of renewables increases, while coal may have a falling PLF, it's not clear when we may expect "peak coal" in terms of total generation from coal – modeling by Mohd.Sahil Ali suggests it won't happen at least until 2030.

3. *Ministry of Environment, Forest and Climate Change (MoEFCC) norms/End of life*: By December 2022, MoEFCC has directed the 161,522 MW of thermal power plants to curtail their SO_x emissions by retrofitting Flue Gas Desulphurisation [FGD] systems over 2018-2022, Central Pollution Control Board, (2018), as per the schedule shown in Figure 14.

Figure 14: FGD implementation plan (2018-22)



This compliance requires on an average one-three months of shutdown to make the necessary upgrades (Pathania, 2018). Assuming all the 161,522 GW power plants are upgraded over this time, at an average of two months, this translates to an additional alternative capacity requirement. Also, many plants require upgradation to meet the PM, NO_x and Electrostatic Precipitator (ESP) upgradation. We simplify this, assuming SO_x dominates retrofits, and any PM retrofit is done simultaneously. In reality, there is a possibility it may take longer.

4. *Reserve margins:* Assuming 5% peak generation reserve margin is observed as stipulated in the Indian Electricity Grid Code (Central Electricity Authority, 2018), India will need additional generation capacity. Currently the reserve margin keeps varying and is not met on many days.

Analysis of peak oriented demand in 2022

Even if all the planned capacity growth of hydro, gas and nuclear is built, we find we would still have unmet peak electricity demand in 2022. In our analysis, the following parameters have been identified to forecast this demand by 2022.

1. Recoverable outage capacity: Three different recoverable outage capacities have been used to model the various scenarios. The recoverable outage depends on various factors like seasonality, availability of fuel etc. The model has used 25 GW, 30 GW and 35 GW as recoverable outage capacity from existing plants.

2. Annual demand growth rate: Three different peak demand growth rates of 5%, 6% and 7% have been used to model the various scenarios. This is done considering the historical evening peak demand growth as well as growth projections based on the work of other scholars (Ali, 2018).

3. Wind availability to meet peak demand: Wind availability factors of 5% and 10% have been used to model for low wind and average wind availability scenarios as coincident with peak demand periods. There are likely a few days where wind may provide much lower. For reference, if wind's installed capacity is 36 GW today (rather, recently), it has on a regular basis produced lower than 3.6 GW of output in the evening.
4. Non-coal new installed capacity: With a non-coal target of 29,980 MW (as calculated from Table 5), three scenarios with 50%, 75% and 100% target achievement have been used.
5. Refurbishment of coal capacity: Two months have been considered as the average time for which a power plant will remain closed for the necessary upgradation to follow the new emission norms for NO_x, SO_x and PM as set by the CPCB. The schedule recommended by the MoEFCC for the refurbishment of the capacity has been used in modelling the outcome.
6. Retirement of old capacity: Old thermal capacity to the order of 22.7 GW (Table 5: Capacity addition and removal by 2022) has been identified to retire by 2022. In the analysis it is assumed that the capacity will be retired in a uniformly staggered manner. However, three different scenarios have been assumed, with 50%, 75% and 100% of the capacity retired.
7. Auxiliary consumption: An auxiliary consumption rate of 2.46% has been assumed for the new non-coal capacity being built.[9] Similarly, an auxiliary consumption of 9.6% has been assumed for the thermal plants retrofitted with FGD upgrades.[10]
8. Transmission losses: Transmission losses of 2% have been assumed[11] (PGCIL, 2019).
9. Plant unavailability: The average unavailability for firm capacity due to technical faults/maintenance for the selected days is calculated to be 11.3% (POSOCO, 2018). We assume that the new non-coal firm capacity will be 50% more efficient than existing capacity, which includes older plants as well. Thus, the unavailability of the new upcoming capacity is assumed at 5.65%. Also, we assume that there won't be any issues of unavailability due to fuel shortages for the new capacity.

[9] Average auxiliary consumption rates for the selected days for non-coal capacity based on NPP data.

[10] Average auxiliary consumption rates for the selected days for coal capacity based on NPP data is 8.6%. A further 1% auxiliary consumption is added due to installation of FGD upgrades.

[11] PGCIL lists 3% as approximate transmission losses. Assuming only part of the new installed capacity uses the PGCIL transmission system, 2% average transmission losses have been assumed (assuming greater than today's average inter-state flows of power).

Table 7: Parameters used to forecast true peak unmet demand

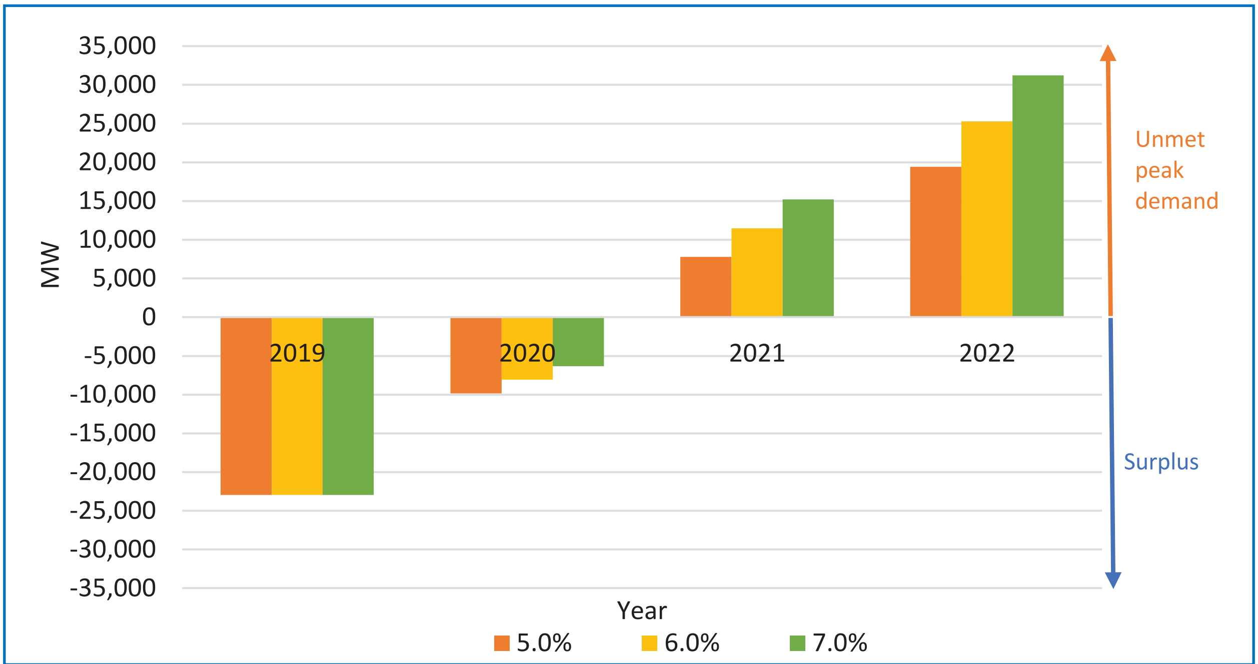
Parameter	Values
Recoverable outage capacity	25 GW/ 30 GW/ 35 GW
Annual peak demand growth rate	5% / 6% / 7%
Wind availability at the peak	5% / 10%
Non-coal new installed capacity (of targets)	50% / 75% / 100%
Existing thermal plants refurbishment time	2 months
Retirement of old capacity (of targets)	50% / 75% / 100%
Auxiliary consumption for non-coal capacity	2.45%
Auxiliary consumption for retrofitted coal capacity	9.6%
Plant unavailability for upcoming non-coal capacity	5.65%

The multiple dimensions analysed via software (Analytica) led to 162 possible outcomes, a large dimensional space. We present nine scenarios to describe the evolution of possible unmet peak demand.

Worst-case scenarios

Assumptions	
Recoverable outage	25,000 MW
Wind available at peak	3,000 MW (5% of 60 GW)
Non-coal non-RE new additional capacity	14,990 MW (50% of 29.88 GW)
Percentage of planned capacity retired	22,700 MW (100% of 22.7 GW)

Figure 15: Worst-case scenarios (unmet peak demand surpasses capacity at the earliest)



Note: The above represents the cumulative demand growth from present to 2022. We observe that there is projected unmet peak demand as early as 2021 in these scenarios.

Mid scenarios

Assumptions	
Recoverable outage	30,000 MW
Wind available at peak	6,000 MW (10% of 60 GW)
Non-coal new installed capacity	22,410 MW (75% of 29.88 GW)
Percentage of planned capacity retired	17,025 MW (75% of 22.7 GW)

Figure 16: Mid scenarios

Note: The above represents the cumulative demand growth from present to 2022. We observe that in 2022, we will witness the cases of unmet peak demand for all three demand growth rates.

Best-case scenarios

Assumptions	
Recoverable outage	35,000 MW
Wind available at peak	6,000 MW (10% of 60 GW)
Non-coal new installed capacity	29,880 MW (100% of 29.88 GW)
Percentage of planned capacity retired	11,350 MW (50% of 22.7 GW)

Figure 17: Best-case scenarios (least/no unmet peak demand)

Note: The above represents the cumulative demand growth from present to 2022. We observe that there is still surplus left in the system till 2022. However, that may not be the case as we move further to 2023.

In most of the scenarios, the peak demand catches up with the peak supply in 2022, and in the worst cases even by 2021.[12]

These scenarios, however, don't consider the 5% reserve generation margin required by the grid. If that is incorporated into the mix, the capacity requirement further increases by around 10-11 GW.

In the mid-scenario, with 6% peak (evening) demand growth, we find that the unmet peak demand is around 8.3 GW in 2022. Either more thermal capacity or equivalent alternate dispatchable capacity needs to be commissioned by 2022 to cater to this demand, unless demand can itself be modified. Otherwise, we might be heading towards a scenario where the demand is higher than what can be supplied by the grid. A similar conclusion has also been reached in other studies (FE Bureau, 2018).

We also explicitly model outages due to environmental retrofits in the time-sequence, and that too conservatively. If it turns out two months aren't sufficient for retrofits, especially in older plants with more space constraints and non-standard plant designs, then the need for alternative capacity increases.

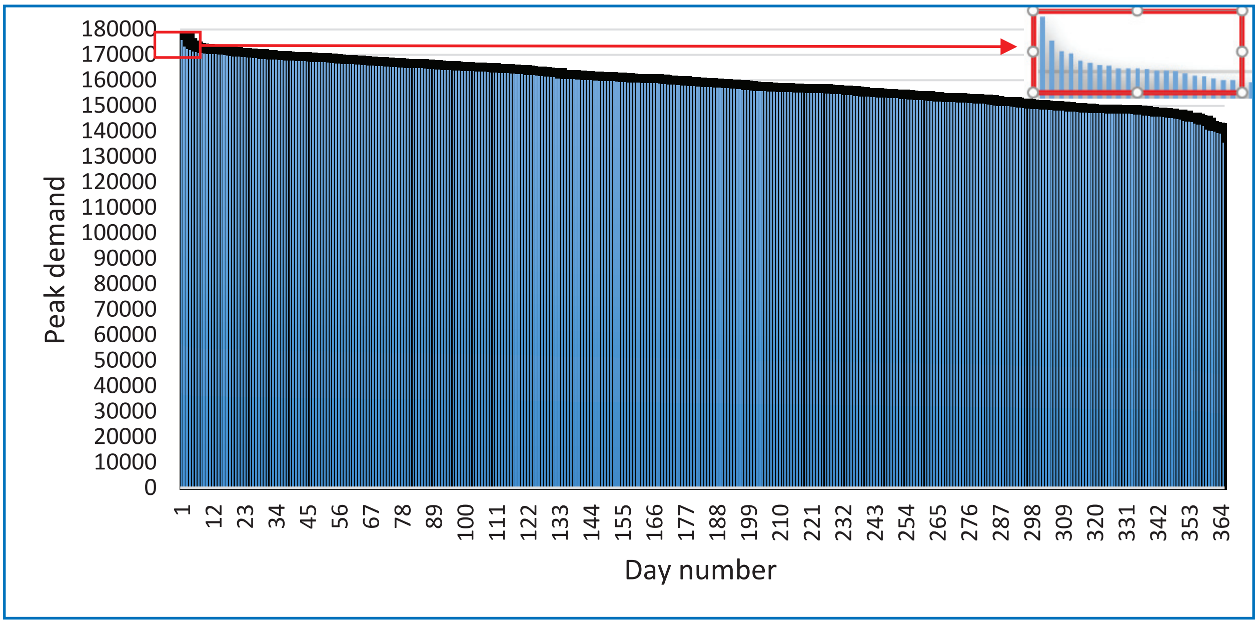
[12] This analysis is based on data from NLDCs. If we instead use the data from CEA, it would add perhaps an additional 3-4 GW of recoverable capacity (assuming pro-rata to explain the differences between data sources). This would not affect our analysis significantly and would just change the capacity addition required in 2021/2022 by 3-4 GW.

How many hours of peak demand per year?

Choice of supply to meet growth (and other factors of downtime) depends on the economics, which depends on how often such capacity will run, i.e., the Plant Load Factor (PLF). PLF depends on the peakiness of demand. Demand can also shift given enough incentives (for evening demand, we assume there is no agricultural supply at this period, so shifting this to mid-day doesn't change the analysis). To begin to answer this question, we examine how many days in a year the peak energy demand rises above a threshold.

Figure 18 shows a stacked all-India daily peak demand distribution over a period of one year, from November 1, 2017 to October 31, 2018.

Figure 18: Daily peak demand (Nov 1, 2017 - Oct 31, 2018), stacked as a peak duration curve (analogous to a load duration curve)



We find the top 1% of the days (3 days) have a daily peak demand over 172 GW and the top 5% of the days (18 days) have a daily peak demand of over 169.5 GW. For the 18 days a year with high demand, it lasts usually during the four hours of the evening. Thus, lacking full time of day data, we can estimate that this demand lasts for 72 hours (18*4) in a year (4 hours per day). Assuming a similar trend in the future, the capacity meeting such demands will have an annual utilisation of 0.83% (72/8670).

New capacity will be required to meet demand at these peak hours, but this should not be a new coal plant unless it's virtually built and a sunk cost. Alternatively, storage solutions might suffice for such peaking, or demand response. Even gas or diesel-based solutions may be most cost-effective when considered in a portfolio basis, even if the per kWh variable cost appears high.

Recommendations and discussion

As this paper shows, the conventional wisdom of India being a vastly power surplus nation needs to be tempered when we consider not energy but instantaneous capacity requirements. The former is talked about in terms of under-utilised and even stranded capacity assets, which also suffer from low PLFs. This is distinct from the problem of meeting the peak demand, often in the evening. As this analysis shows, to meet the evening peak, when RE is often limited, the present capacity surplus may exhaust in two-three years.

What constitutes as outage also needs to be reconsidered. Do the power plants under demand/ scheduling shutdowns constitute as outage plants? As these plants will be the first ones to come online for meeting new demand, they could be placed under a separate category, for example, “reserves”. Placing them under “outages” does not convey their ability to come online when the demand arises.

India needs to focus on real-time (instantaneous) capacity-oriented planning, which is missing today. Bids for new plants today focus on LCOE (levelised cost of energy) without factoring in their value or contribution to capacity requirements, which inherently should factor in time of day. Demand will rise exogenously – supply outages need to be addressed, such as the lack of coal or gas, spanning issues of coordination, contracts, etc.

More than just time of day differentiation, the general norm of “availability” to meet contractual obligations (often at 85% availability) itself needs innovation. While some true outages are inevitable, contracts should signal value and incentivise higher availability when the grid needs peak demand. As a thought exercise, we can bound two synthetic scenarios of outages. The first is if all outages are spread out as much as possible across plants. Thus, thermal plants with a notional 15% allowed outage (or, say, 1/6) mean they can be out two months per year, so a capacity of 200 GW (pre-auxiliary and other losses) is effectively a 167 GW gross capacity). In contrast, even a 1% outage can be fatal to the grid if all plants have outages simultaneously. The best-case scenario is one where planned outages are scheduled based on grid (net) demand, and, for example, scheduled during low demand seasons. Some generators do this (especially state-owned), but it is not universal and certainly not signaled to private generators.

For the present plants, environmental upgradations are more concentrated in 2021 and 2022. These are the years when the capacity surplus will have decreased more than in the earlier years. Hence, it makes more sense to prepone the environmental upgradations and to frontload them to years when the demand is lower. Postponing the upgrades could even lead to missing the 2022 deadline for some plants (if they are used to meet the projected increased demand).

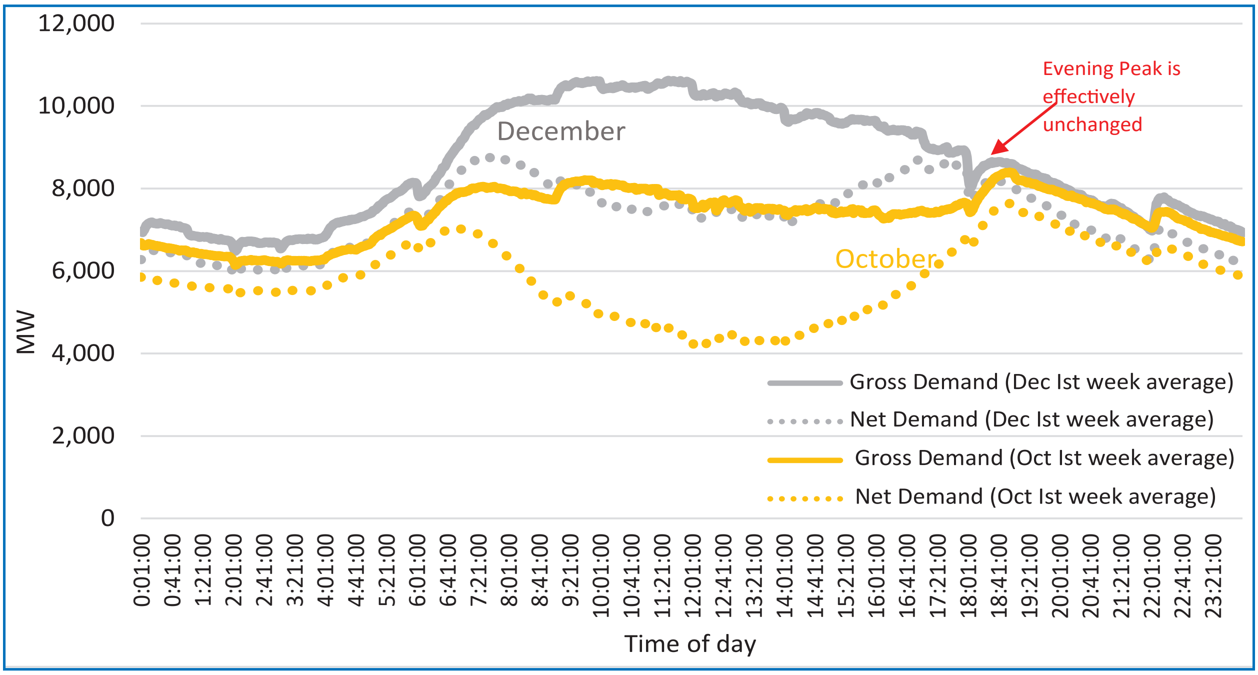
While we do not advocate any leniency in the overall push for improved environmental emissions, a more nuanced approach may find value to not retiring all capacity that cannot retrofit (for space and/or economic reasons), but limiting it to emergency or strictly limited use, for example, 100 hours in a year to supply at the top 5% time of the peak demand as described in Figure 18. Age of plant is in and of itself not a sufficient marker for which plants should be retired, for example, after 25 years. A well-maintained old plant could easily last much longer. As an example, in 2017, the average US coal plant was about 39 years old (US Energy Information Administration, 2017).

Given the relatively shallow usage of peak-duration suppliers, Indian planners must focus on peakers, demand shifting, and storage. There is around only 700 MW of diesel generation present as grid supply in the grid, but there is at least 90 GW owned by consumers (CERC, 2014).[13] However, demand is continuously growing. Today's annual peak demand will be closer to the average daily peak demand in the coming years. However, a power plant catering to peak demand today should cater to peak demand tomorrow as well. We should build plants such that increase in base load is shared by base load plants and not peakers. Thus, we need a deep dive analysis to determine the optimal generation mix from the perspectives of demand growth, economics, GHG emissions, energy security and grid stability.

Adding supply used to be the means of matching supply and demand – in a world of higher RE this becomes trickier unless it's "appropriate" supply. An alternative is to shift demand in response to grid conditions. In the future, at higher RE penetrations, Demand Response (DR) can help grid management without requiring as much storage (or RE curtailment) as otherwise.

We have discussed how the peak demand is concentrated in the evenings. However, there is an important caveat to the so-called "evening peak". Many states are looking at using solar to power irrigation pumpsets, essentially shifting demand to periods of high (and cheap) supply. In contrast to the Maharashtra model of solar feeders (Gambhir & Dixit, 2018), or even solar water pumps, Karnataka instituted agricultural feeder supply to sync with solar power starting November 2018. While this has measurably shifted demand from the night to the day, shifting thousands of MW of load and effectively flattening the net demand curve, it did not change the "evening peak" demand (Figure 18) significantly. This is because agricultural supply is not scheduled during the evening peak period, a practice true in most states. This emphasises the need for India to begin measuring and signaling "net demand", which is demand post RE supply, i.e., treating RE as negative demand.

Figure 19: Limits to agricultural load shifting via solar power – State demand profile of Karnataka averaged over the first week of October and first week of December



Source: KPTCL SLDC data as compiled by authors

[13] More recent unofficial estimates peg consumer-owned diesel back-up closer to 110-120 GW if not more. This is before we consider under-utilised captive power as a possible grid participant.

This shows how the net demand (gross demand minus RE generation) changed after Karnataka began shifting its agricultural load from previously off-peak (night) periods to mid-day in November, to match high solar output. While the day shapes have changed measurably, the evening peak is relatively similar. It has also significantly trimmed the belly of the net demand curve from a ramp requirement of around 3,300 MW to around 1,000 MW. This significantly increases the PLF of the thermal plants; as well as decreases the need of high ramping by hydropower, effectively conserving it as a strategic reserve.

This study was meant to inform policy discourse and does not claim to give precise numbers for planning. It has been done on a national level. Regional and state-level studies will be able to add more nuances to our understanding of the problem. Similarly, more granular data, on an hourly/minute basis will allow us to better understand the interaction of RE with the grid, and to come up with better approaches to optimise our generation capacity for the future. In addition to demand, if data were available, we should focus on net demand (post RE). Lastly, we recognise the limitations of data, such as the sampling-based approach using POSOCO / RLDC data. The intent was to see representative ranges for the parametric analysis, as opposed to a statistical analysis, and hence believe this is a worthwhile approach for the study.

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